nationalgrid

October 20, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4647 - 2016 Gas Cost Recovery Filing
Responses to Division Data Requests – Set 3

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] responses to the third set of data requests issued by the Rhode Island Division of Public Utilities and Carriers (Division) in the above-referenced docket.

This filing also contains a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain confidential and proprietary information, which is contained in the Company's response to Division 3-2. In compliance with Rule 1.2(g), the Company has also provided the PUC with the un-redacted, confidential version of this response in a sealed envelope marked, **"Contains Privileged and Confidential Materials – Do Not Release"**, and has included a redacted copy in the filing.

Thank you for your attention to this filing. If you have any questions, please contact Jennifer Brooks Hutchinson at 401 784-7288 or Robert Humm at 401-784-7415.

Very truly yours,

Jennifer Brooks Hutchinson

Robert J. Humm

Enclosures
cc: Leo Wold, Esq.
Steve Scialabba, Division
Bruce Oliver, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2016	))))	Docket No. 4647

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2(g)(2).

I. BACKGROUND

On October 20, 2016, the Company filed with the PUC its responses to the third set of data requests from the Division of Public Utilities and Carriers (Division) in this docket. The written response to Division 3-2 contains privileged and confidential information. Specifically, Division 3-2 seeks information concerning confidential gas-cost pricing information relating to options for supply calls at Texas Eastern M3. National Grid is seeking protective treatment for such confidential gas-cost pricing information.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

II. LEGAL STANDARD

Rule 1.2(g) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq*. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that the determination as to whether this exemption applies requires the application of a two-pronged test set forth in *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001). The exemption applies where the disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *See Providence Journal*, 774 A.2d 40.

The first prong of the test assesses whether the information was provided voluntarily to the governmental agency. *Providence Journal*, 774 A.2d at 47. If the answer to the first question is affirmative, then the question becomes whether the information is "of a kind that would customarily not be released to the public by the person from whom it was obtained." *Id.*

III. BASIS FOR CONFIDENTIALITY

The gas-cost pricing information included in National Grid's responses to the Division's third set of data requests are confidential and privileged information of the type that National Grid would not ordinarily make public. Moreover, public disclosure of such information could impair National Grid's ability to obtain advantageous pricing in the future, thereby causing substantial competitive harm. Accordingly, National Grid seeks protection for such confidential information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID

By its attorneys,

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Jennifer Brooks Hutchinson, Esq. (#6167)
Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: October 20, 2016

Division 3-1

Request:

Please verify that the Company's revised gas costs filed on October 3, 2016:

a. Have been revised solely for the purpose of reflecting the costs of the market area hedges discussed in the September 2016 testimony of Witness McCauley. If this is incorrect, please itemize all other factors for which adjustments to the Company's 2016-17 GCR costs have been made in the Company's October 3, 2016 filing.

b. Do not include any costs for the options for "*supply calls at Texas Eastern/M3*" for the months of December 2016, January 2017, and February 2017 discussed in Witness Arangio's September 1, 2106 testimony at page 14. If this is incorrect, please document all costs that are included in the Company's October 3, 2016 filing to address those call options.

c. Do not include costs for the firm liquid service for the portable LNG that the Company plans to have available for the winter of 2016-17. If this is incorrect, please document all costs that are included in the Company's October 3, 2016 filing to address Company's efforts to secure firm liquid service for the portable LNG facility referenced in Witness Arangio's direct testimony at pages 15-16.

Response:

a. Yes. In the Company's October 3, 2016 filing, the GCR costs were revised only to reflect the changes due to the impact of the market area hedges discussed in the September 2016 testimony of Witness McCauley. This gas cost revision also impacted the Company's working capital amount, as highlighted in Attachment AEL-1 Revised, page 8.

b. The Company's gas costs filed on September 1, 2016. and subsequently revised on October 3, 2016. includes costs for the options for *"Supply Calls at Texas Eastern/M3"*. Please refer to the following: (1) Witness Arangio's Confidential Attachment EDA-2 Revised, page 11 of 17, under the heading "Supplier Fixed Cost Unit Prices," labeled as "Supply Call at Tetco M3." (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 83 Columns B thru N). (2) Witness Arangio's Confidential Attachment EDA-2 Revised, page 12 of 17, under the heading "Supplier Fixed Cost Billing Units," labeled as "Supply Call at Tetco M3." (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 162 Columns B thru N). (3) Witness Arangio's Confidential Attachment EDA-2 Revised, page 14 of 17, under the heading "Total Supplier Demand Cost," labeled as "Supply Call at Tetco M3." (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 246 Columns B thru N).

c. The Company's gas costs filed on September 1, 2016 and subsequently revised on October 3, 2016 include the costs for the firm liquid service for the portable LNG that the Company plans to have available for the winter of 2016-17. Please refer to the following: (1) Witness Arangio's Confidential Attachment EDA-2 Revised, page 11 of 17, under the heading "Supplier Fixed Cost Unit Prices," labeled as "ENGIE GAS DEMAND PAYMENT (winter)." (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 81 Columns B thru N). (2) Witness Arangio's Confidential Attachment EDA-2 Revised, page 12 of 17, under the heading "Supplier Fixed Cost Billing Units," labeled as "ENGIE GAS DEMAND PAYMENT (winter)" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 160 Columns B thru N). (3) Witness Arangio's Confidential Attachment EDA-2 Revised, page 14 of 17, under the heading "Total Supplier Demand Cost," labeled as "ENGIE GAS DEMAND PAYMENT (winter)." (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs 10-14, Row 244 Columns B thru N).

Redacted

Division 3-2

Request:

Re: Witness Arangio's Direct Testimony at page 13 of 23, line 16, through page 14 of 23, line 10, please:

a. Document by month and in total the costs of options for supply calls at Texas Eastern/M3 for the months of December 2016, January 2017, and February 2017;

b. Explain where within the Company's filing the costs of the referenced options for supply calls are reflected and document the inclusion of those costs;

c. Provide the data, analyses, workpapers and studies upon which the Company relies to assess the reasonableness of the costs of the referenced supply calls at Texas Eastern/M3.

Response:

a. The final costs of options for supply calls at Texas Eastern M3, by month and in total, are set forth below:

Dec 16	Jan 17	Feb 17	Total
$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]

b. Please see the Company's response to Division 3-1(b) for the location of the costs of the referenced options for supply calls within the Company's filing. In particular, please refer to Witness Arangio's Confidential Attachment EDA-2 Revised, page 14 of 17, under the heading "Total Supplier Demand Cost," labeled as "Supply Call at Tetco M3" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 pgs. 10-14, Row 246 Columns B thru N), which shows a monthly amount of $[redacted] and a total cost of $[redacted]. At the time of filing, this was the best available information and assumption of costs based on bids received during the RFP process. The terms and conditions for the contracts are now finalized with counterparties. The costs shown above in response to Division 3-2(a) represent the final costs.

c. Texas Eastern continues to strive for restoration of full service by November 1, 2016. However, the Delmont outage and associated restrictions are presently still in place, as described in the handout provided by Spectra at the September 1, 2016 customer meeting (and provided in the Company's response to the Division's Data Request 2-3 (a) at Attachment DIV 2-3(a)). The maximum volume designed to flow through Delmont is

Division 3-2, page 2

2.6 BCF per day. Currently, only 1.1 BCF per day is able to flow – approximately 40% of the total capacity – which equates to a restriction of approximately 60%. A 60% restriction would have a significant impact on the availability of supplies at Lambertville, New Jersey into Algonquin. If the foregoing restriction remains in place for the winter, it would equate to a reduction of 32,073 Dth per day available to the Company through Texas Eastern and, therefore, into Algonquin for delivery to the Company's citygates. To put this into perspective, the Company maintains a total of 152,705 Dth per day of Algonquin capacity. A 60% restriction through Delmont on Texas Eastern would result in a reduction of 21% of the Company's available gas supplies on Algonquin. Assuming near design or design weather conditions, the Company would have an extremely difficult time meeting customer requirements without 21% of its supply on Algonquin. In order for Spectra to restore full service, the work plan includes, among other tasks, the inspection of 626 anomalies as well as hydrostatic testing of miles of pipe, and the need for permits from multiple state and local agencies. The immensity of the effort cannot be understated.

In its September 1 handout, Spectra provided two other scenarios for planning purposes – one which resulted in a 50% restriction of the flows through Delmont, and the other which resulted in a 30% restriction of the flows through Delmont. Given the Company's need for volumes from Lambertville to meet customer requirements, the Company took action to secure the availability of supplies at Lambertville. The Company planned for an approximately 40% restriction of the flows through Delmont. The Company believes its contingency planning was prudent in that it secures the availability of supplies at Lambertville to meet the much needed customer requirements in both a normal winter and a design winter downstream of the Delmont receipt point.

If the Delmont section of the pipe returns to full service, then the contingency plan will allow the Company to continue to purchase supplies at the lower-cost supply areas of Texas Eastern zone M2. If capacity is restricted through the Delmont section of the pipe, then the contingency plan will provide the Company the firm contractual rights to call on supplies downstream of the Delmont section. The Company's option to call on supply is critical if capacity is restricted through the Delmont Compressor, because supplies downstream will be more difficult to acquire as all firm shippers will be looking for replacement supplies, most likely during periods of high demand. Having the contractual right to call on supply during periods of high demand, or less liquid areas, ensures that sufficient supplies will be available to meet the Company's requirements on colder than normal days.

Division 3-3

Request:

Re: Witness Arangio's Direct Testimony at page 15 of 23, line 11, through page 16 of 23, line 2, please:

a. Identify each line item within Attachment EDA-2 that reflects costs associated with the replacement of supply from the Cumberland LNG tank;

b. Document and explain the treatment within the Company's 2016-17 GCR investment costs (including return and taxes), and depreciation, maintenance and operating expenses associated with the Cumberland LNG tank which has been removed from service.

Response:

a. The Company's gas costs filed on both September 1, 2016, and subsequently revised on October 3, 2016, include the costs associated with the replacement of supply from the Cumberland LNG tank. The replacement supplies include both the firm liquid service for the portable LNG, as well as the volumes to be purchased at Dracut and transported on the newly acquired Tennessee capacity to the Company's citygates. For the LNG supplies, please refer to the following: (1) Witness Arangio's Confidential Attachment EDA-2 Revised, page 11 of 17, under the heading "Supplier Fixed Cost Unit Prices," labeled as "ENGIE GAS DEMAND PAYMENT (winter)" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs. 10-14, Row 81 Columns B thru N). (2) Witness Arangio's Confidential Attachment EDA-2 Revised, page 12 of 17, under the heading "Supplier Fixed Cost Billing Units," labeled as "ENGIE GAS DEMAND PAYMENT (winter)" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs. 10-14, Row 160 Columns B thru N). (3) Witness Arangio's Confidential Attachment EDA-2 Revised, page 14 of 17, under the heading "Total Supplier Demand Cost," labeled as "ENGIE GAS DEMAND PAYMENT (winter)" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs. 10-14, Row 244 Columns B thru N).

For the Dracut supplies, please refer to the following: (1) Witness Arangio's Confidential Attachment EDA-2 Revised, page 11 of 17, under the heading "Supplier Fixed Cost Unit Prices," labeled as "Peaking supply at Dracut" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs. 10-14, Row 82 Columns B thru N). (2) Witness Arangio's Confidential Attachment EDA-2 Revised, page 12 of 17, under the heading "Supplier Fixed Cost Billing Units," labeled as "Peaking supply at Dracut" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 pgs. 10-14, Row 161 Columns B thru N). (3) Witness Arangio's Confidential Attachment EDA-2 Revised, page 14 of 17, under the heading "Total Supplier Demand Cost," labeled as

Division 3-3, page 2

"Peaking supply at Dracut" (provided in Excel File EDA 1 2 Gas Costs 16_17 Revised Confidential Tab EDA-2 Pgs. 10-14, Row 245 Columns B thru N).

b. The Company's GCR mechanism does not recover capital costs (i.e., return, taxes, depreciation, and property taxes) associated with the Company's Cumberland LNG tank. The GCR does, however, include the recovery of $1,148,275 in total LNG O&M expenses (see Attachment AEL-1 Revised, Page 2, Line 8, and Page 3, Line 7). This amount represents the sales customer's share of the total LNG O&M supply-related production and storage costs for the 2013 rate year as determined in the Company's most recent general rate case in Docket No. 4323. This amount is fixed until the Company's next general rate case, pursuant to the Company's gas tariff. See RIPUC NG-GAS No. 101, Section 2 (Gas Charge), Schedule A, Sheet 4. The Company estimates that approximately $210,000 of the $1,148,275 is attributed to the Cumberland LNG Facility.

Division 3-4

Request:

Please detail the costs that National Grid has incurred maintain the Cumberland LNG tank in each of the last three GCR years and in the current GCR year to date.

Response:

FY 14 ~ $879,000 * These O & M charges also include Exeter.
FY 15 ~ $473,000
FY 16 ~ $510,980
FY 17 ~ $246,663 (as of Sept. 2016)

Prepared by or under the supervision of: Kathleen Sullivan

Division 3-5

Request:

Please provide the Company's best estimates of the impact of the its decision to take the Cumberland LNG tank out of service on its LNG O&M costs for the 2016-17 GCR year. If the removal of the Cumberland LNG tank from service has no impact on the Company's LNG O&M costs, please explain how such impacts are avoided.

Response:

The impact will have a slight increase due to the portable operation, including trucking and labor charges, for the 2016-17 GCR year with variation depending on weather. Please also see the Company's response to Division 3-3 regarding the impact to LNG O&M expense in the GCR factor.

Prepared by or under the supervision of: Kathleen A. Sullivan

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<u>Division 3-6</u>

<u>Request</u>:

Please identify all alternatives for meeting the service requirements previously addressed by the availability of gas from the Cumberland LNG Tank, including but not limited to:

a. The estimated costs for repairing the existing LNG tank;
b. The estimated costs for demolishing the existing LNG tank and building a new Tank.

<u>Response</u>:

a. The Company has determined that, primarily for safety reasons, repairing the existing LNG tank is not a viable option and, therefore, decided to permanently remove the tank from service. After discovery of a temperature anomaly within the tank, the Company's engineering report concluded that water had infiltrated through the tank foundation and into the insulation blocks, creating a "cold spot." Although the tank is not currently leaking and the Company does not believe that the tank's integrity has been compromised, it is impossible to know whether there has been damage to the tank that could result in a future failure without visually inspecting the inside of the tank. Also, the manufacturer's engineering report suggests that decommissioning the tank to inspect it would likely compromise the tank's integrity. Therefore, inspecting and refilling the tank would be considered a high-risk activity and is not a viable option.

b. The cost for demolition has not yet been determined. The estimate of a new LNG tank would be in excess of $75 million.

Prepared by or under the supervision of: Kathleen Sullivan

Division 3-7

Request:

For each day identified in the Company's response to Division Data Request 1-1, please provide:

a. The sendout in MMBtu from the Cumberland Gate Station;

b. The sendout in MMBtu from the Lincoln Gate Station;

c. The sendout in MMBtu from the Cumberland LNG Tank;

d. The portion of the total Cumberland System Sendout in MMBtu that represented sendout for Zero Capacity (i.e., Capacity Exempt) transportation service customers;

e. The portion of total system sendout in MMBtu that represented sendout for Zero Capacity (i.e., Capacity Exempt) transportation service customers.

Response:

a. Please see the Table below at Column (a) for the Sendout in MMBtu from the Cumberland Gate Station.

b. Please see the Table below at Column (b) for the Sendout in MMBtu from the Lincoln Gate Station.

c. Please see the Table provided in Division 1-1 labeled (b) for the Sendout in MMBtu from the Cumberland LNG Tank.

d. Please see the Table below at Column (d) for the portion of the total Cumberland System Sendout in MMBtu that represents sendout for Zero Capacity (i.e. Capacity Exempt) transportation service customers.

e. Please see the Table below at Column (e) for the portion of total system sendout in MMBtu that represented sendout for Zero Capacity (i.e. Capacity Exempt) transportation service customers.

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-7, page 2

Year	Date	(a.) Cumberland Gate Station MMBtu	(b.) Lincoln Gate Station MMBtu
2013			
	11-Dec	24,645	16,944
	31-Dec	27,354	18,697
2014			
	2-Jan	20,233	16,318
	3-Jan	27,682	23,294
	7-Jan	30,176	24,199
	22-Jan	34,233	23,183
	23-Jan	33,404	22,954
	26-Feb	27,141	19,424
	27-Feb	27,722	22,226
	5-Mar	22,968	20,030
	26-Mar	21,671	14,747
	31-Dec	24,564	16,477

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-7, page 3

Year	Date	(a.) Cumberland Gate Station MMBtu	(b.) Lincoln Gate Station MMBtu
2015			
	7-Jan	26,666	23,170
	28-Jan	29,551	18,359
	15-Feb	33,501	23,669
	16-Feb	33,882	23,054
2016			
	19-Jan	27,909	19,944
	8-Feb	23,323	20,999
	11-Feb	29,215	22,692
	12-Feb	22,396	20,296
	13-Feb	28,990	24,867
	14-Feb	30,225	25,337
	15-Feb	17,619	16,666

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-7, page 4

Year	Date	(d.) Cumberland System Capacity Exempt MMBtu	(e.) Total system Capacity Exempt MMBtu
2013			
	11-Dec	17,281	25,932
	31-Dec	12,743	19,506
2014			
	2-Jan	14,486	22,392
	3-Jan	15,351	23,416
	7-Jan	15,000	23,153
	22-Jan	15,613	24,030
	23-Jan	15,494	23,769
	26-Feb	14,524	22,038
	27-Feb	14,652	22,268
	5-Mar	14,282	21,789
	26-Mar	16,902	25,727
	31-Dec	15,683	26,925

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-7, page 5

Year	Date	(d.) Cumberland System Capacity Exempt MMBtu	(e.) Total system Capacity Exempt MMBtu
2015			
	7-Jan	15,611	26,483
	28-Jan	15,578	25,785
	15-Feb	13,160	23,954
	16-Feb	13,423	24,169
2016			
	19-Jan	14,080	23,899
	8-Feb	17,650	29,235
	11-Feb	14,140	24,224
	12-Feb	13,330	23,066
	13-Feb	14,723	25,557
	14-Feb	15,108	25,923
	15-Feb	13,613	23,011

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 3-8

Request:

Please provide the workpapers, data, analyses, and studies upon which the Company relies to assess that a total of 30,000 MMBtu per day of capacity (i.e., 24,000 MMBtu of capacity at Dracut and 6,000 MMBtu per day of portable LNG capacity are required to ensure the reliability of service in the area formerly served by Cumberland LNG Tank to ensure the reliability of service to Firm Sales Service customers and Firm Capacity Assigned Transportation Service customers in that area for:

a. The winter of 2016-17
b. The winter of 2017-18

Response:

a. & b. Please see the documentation below for the studies the Company performed to determine the need for the portable LNG capacity (7,000 dth/day) for the winter of 2016-17. The similar requirements would be expected for the winter of 2017-18.

I. Objective

Determine the volume of LNG required from Cumberland, if any, in order to pressure-balance the gas system if the Cumberland LNG site was unavailable for the winter and/or the Cumberland Take Station was required to stay within maximum daily quantity contract limitations.

II. Summary

Long Term Planning would require LNG at Cumberland at a volume equivalent to 760 dth/hr at approximately 9 hours for the winter of 2016/17 in order to support a design day event.

III. Assumptions

- Additional supply volume (of 24,000 dth/D) from Lincoln Take Station supplies the 99 psig system.
- Hourly volume at the Cranston Take Station is not a limitation, as this volume is expected to be exceeded regardless.
- Providence LNG is set to provide approx. 125 psig inlet to the Allens Ave 99 psig regulators.
- The flow from the Cranston Lateral is limited by allowing the Cowesett valve to only flow to maintain 50 psig back pressure.

Division 3-8, page 2

- This analysis does not account for any needs by Gas Supply or Gas Control to operate the system for other means.

IV. Winter Weather Data & Peak Day Forecast

The latest weather and peak day forecast provided by Analytics Forecasting group for Rhode Island from June 2016 was utilized for the analysis. Only the weather from the Winter Season (Nov 1 to Mar 31) was calculated and the results summarized below by temperature ranges matching Operation Models:

TABLE - 1

Average Daily Temp (F)	Average Daily HDD	# of Days Design Winter
35	25-30	30
30	30-35	13
25	35-40	29
20	40-45	30
15	45-50	6
10	50-55	2
5	55-60	3
0	60-65	0
-3	65-68	1

V. Daily Flow Patterns

The hydraulic models are steady-state modeled as a 5% Peak Hour Factor (PHF). This is defined as the maximum hourly flow as a percentage of the total daily volume. In order to determine the need for volumes throughout the course of a day, historical data for the past two calendar years (2014 and 2015) was evaluated to determine variability in flows. While variability occurs in the hourly flows as a percentage of the day, no significant correlation was found relative to Heating Degree Days. A plot of the percent of hourly flow by HDD is attached in Appendix 1.

In addition, to find relative flow comparisons against the modeled peak-hour flows, factors were created based upon average hourly flows. The plot of historical flows by the hour is attached in Appendix 2, along with the factors by the hour in Appendix 3. The factors are additionally presented in the table below:

Division 3-8, page 3

TABLE - 2

Hour	Average % of Daily	Factor of 5% Peak Hour
11 AM	4.68%	94%
12 PM	4.54%	91%
01 PM	4.34%	87%
02 PM	4.19%	84%
03 PM	4.04%	81%
04 PM	3.99%	80%
05 PM	4.09%	82%
06 PM	4.25%	85%
07 PM	4.35%	87%
08 PM	4.35%	87%
09 PM	4.27%	85%
10 PM	4.06%	81%
11 PM	3.78%	76%
12 AM	3.52%	70%
01 AM	3.38%	68%
02 AM	3.34%	67%
03 AM	3.37%	67%
04 AM	3.45%	69%
05 AM	3.69%	74%
06 AM	4.20%	84%
07 AM	4.95%	99%
08 AM	5.30%	106%
09 AM	5.07%	101%
10 AM	4.82%	96%

For the instances where the Factor of the Peak Hour is above 5%, the peak hour flows were used.

VI. Flows Analysis

The hydraulic model from Winter Operations was simulated with the modifications to the 99 psig system delivery supply points. The maximum flows at Cumberland & Lincoln were set near contract limitations (1,350 mcfh at Cumberland and 1,250 mcfh at Lincoln). This limitation resulted in lower set pressures to maintain on the 99 psig system. Cumberland was limited to 87 psig and Lincoln was limited to 93.5 psig. It was determined that the Cumberland LNG site was required to maintain approx. 90 psig in order to pressure balance the gas system. Any decrease in pressure from 90 psig lead to pressures below minimum design on the downstream LP systems as a result of LP stations not being able to maintain sufficient set points. The resultant LNG flow at Cumberland to maintain this pressure on a design day was 759 dth/hr.

The model flows for each HDD that LNG was required was converted to flows for each hour utilizing the percentage of the peak hour factor as shown in Table – 2. Any hourly flows resultant for that HDD were separated and matched to an equivalent peak hour LNG pressure support flow. For instance, a Peak Day (68 HDD) when separated for 24 hours showed 5 hours flowing above 19,248 dth (thus equivalent to a 68 HDD peak hour flow) & 4 hours above 17,903 dth (equivalent to 60 HDD). A summary of hours above modeled peak hour flows results is shown in the following:

TABLE – 3

HDD	Hours Per Day Equivalent to Peak Hour for:		
	60 HDD	65 HDD	68 HDD
60	5	-	-
65	4	5	-
68	7	4	5

This data was used to multiply the hours per day by the LNG pressure peaking flows for their matching HDD and the number of days expected in the design winter to achieve the seasonal volume results for each different HDD expected below:

TABLE - 4

HDD	LNG Flows
35	-
40	-
45	-
50	-
55	-
60	-
65	3,800
68	6,840

As no 60-65 HDD is anticipated (reference Table – 1), the seasonal volume is equivalent to that volume anticipated on the event of a Peak Day, i.e. 6,840 dth.

Please refer to the Company's response to Division 2-10 (a) and (d) for the analysis that was performed to determine the requirements for Dracut capacity. Please see the Company's response to Division 3-11 for copies of Appendices 1-3 referenced above. In addition, the chart below shows the customer requirements for both the peak day and peak season for 2016-17 and 2017-18.

Division 3-8, page 5

	2016/17 (MMBtu)	2017/18 (MMBtu)
TOTAL Peak Day (Jan 19th)	357,153	361,468
Valley	62,916	63,676
Westerly	5,551	5,618
Warren	8,878	8,985
Providence	279,808	283,189
	357,153	361,468
TOTAL Peak Season (Nov-Mar)	26,826,659	27,135,025
Valley	4,725,782	4,780,103
Westerly	416,930	421,722
Warren	666,838	674,503
Providence	21,017,110	21,258,697
	26,826,660	27,135,025

Division 3-9

Request:

Please provide the workpapers, data, analyses and studies upon which the Company has relied to assess the probability that it will require Portable LNG capacity at the site of the Cumberland LNG Tank:

a. During the winter of 2016-17
b. During the winter of 2017-18

Response:

a. Please see the Company's response to Division 2-9, filed on September 23, 2016, and the Company's responses to Division 3-8 and Division 3-11.

b. Please see the Company's response to Division 2-9, filed on September 23, 2016, and the Company's responses to Division 3-8 and Division 3-11. At this time, given forecasted customer requirements for next year, the Portable LNG capacity continues to be needed for the winter of 2017-18.

Prepared by or under the supervision of: Adnan Malik

Division 3-10

Request:

Re: Witness Arangio's Direct Testimony at page 15 of 23, lines 3-7, please:

a. Update the status of the Company's decision with respect to exercise of its option to secure the referenced incremental 24,000 Dth of capacity at Dracut for the winter of 2017-18;

b. Provide the data, analyses, workpapers and studies upon which the Company has relied or will rely to assess:

   i. Its need for the incremental 24,000 Dth of capacity at Dracut for the winter of 2017-18;

   ii. The costs of securing the incremental 24,000 Dth of capacity at Dracut for the winter of 2017-18;

   iii. The economics of alternatives to securing the incremental 24,000 Dth of capacity at Dracut for the winter of 2017-18.

Response:

a. The Company is paying Tennessee's maximum tariff rate (zone 6 to zone 6) for such capacity and, as such, is granted a right of first refusal on the capacity for next year. As required under Tennessee's tariff, the Company must decide by October 31, 2016 in order to secure the capacity for next year (November 2017 – October 2018). In order to make the determination on whether to renew the capacity, the Company will perform the same analysis as described in the Company's response to Division 2-10 and Division 3-8. At this time, given forecasted customer requirements for next year, the Tennessee Pipeline capacity continues to be needed.

b.

   i. Please see the Company's response to Division 2-10 (a). At this time, given the forecasted customer requirements for next year, the Tennessee Pipeline capacity continues to be needed.

   ii. Please see the Company's response to Division 2-10 (c).

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-10, page 2

iii. Assuming no replacement for the Cumberland LNG volumes, the Company would not be able to meet customer requirements under design weather conditions. As referenced in the Company's response to Division 2-8, there are no practical alternatives available to the Company as a result of the location of the Cumberland LNG tank as well as the configuration of the Company's distribution system. The loss of this source of supply cannot be replaced by deliveries to any of the other Tennessee gate stations nor can it be replaced by additional deliveries to any of the Company's Algonquin gate stations.

The Cumberland LNG tank provides gas supplies to an isolated portion of the Company's distribution system, which is fed only by the Tennessee Pipeline and the Cumberland LNG tank. Without the Cumberland LNG tank, the only options to feed this portion of the system are through the existing Tennessee citygate stations and/or portable LNG. The peak day forecast for this upcoming winter for this isolated portion of the system totals 62,916 Dth. The Company has 32,238 Dth per day of existing capacity to Scott Road and 6,800 Dth per day available of existing capacity to Lincoln, resulting in a 23,878 Dth peak day deficiency. When faced with this outcome, and knowing that no third party maintains primary point capacity to any of the Company's Tennessee Pipeline meter stations, the Company contacted Tennessee to determine the availability of capacity to either or both of the Company's citygates.

The ability to provide portable LNG to meet a design day need of 23,878 Dth is logistically infeasible, as it would require the need for a minimum of 25 truckloads of LNG on the peak day, even before taking into account the need for additional supply to meet hourly peaks throughout the day. In the absence of any alternatives, when Tennessee notified the Company of the availability of capacity from Dracut to the Company's Lincoln citygate for a volume of 24,000 Dth per day, the Company made the decision to proceed with securing the capacity with primary point deliverability for the upcoming winter.

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 3-11

Request:

Re: Witness Arangio's Direct Testimony at page 16 of 23, lines 3-7, please:

a. Provide the Company's assessment of the probability that it will require liquid service for portable LNG during the winter of 2016-17;

b. Provide the Company's assessment of the degree day level at which it would expect to dispatch portable LNG for the Cumberland System during the winter of 2016-17.

c. Detail the costs that National Grid will incur for the winter of 2016-17 to ensure the availability of:

    i. Firm liquid service for portable LNG to replace Cumberland Tank supplies;

    ii. Trucks and drivers to deliver liquid to support portable LNG supply requirements for the Cumberland System.

Response:

a. National Grid uses a degree day measure with a frequency of one occurrence in 98.86 years to depict the "Design Day" conditions used in its planning. The Company's design day and design year forecast underlies its gas resource planning decisions. A Design Day is defined as 68 heating degree days (HDD), which is within the range of values based on the cost benefit analysis in the Company's 2016 Long Range Plan.

   In order to ensure that the Company is able to serve all customers on a Peak Day in 2016-2017, the Company would expect to use its portable LNG during a Design Day event during the winter of 2016-2017. However, given that this will be the first winter without the availability of the Cumberland LNG tank, the Company may need to call on its portable LNG on days other than the Design Day. This will only be known in real-time as the Company gains experience of operating the system with the Cumberland LNG tank.

b. Please see the Company's response to Division 3-8.

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Division 3-11, page 2

c.

i. Please see the Company's response to Division 1-3.

ii. The Company is in the process of securing trucks and drivers to deliver liquid to support portable LNG supply requirements for the Cumberland System.

Prepared by or under the supervision of: Elizabeth Arangio & Adnan Malik

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Division 3-12

Request:

Re: Witness Arangio's Direct Testimony at page 19 of 23, please provide complete copies of the "Precedent Agreements" that the Company has entered into for:

a. Liquefaction services at the NGLNG facility;
b. Liquefaction services at the Northeast Energy Center, LLC

Response:

a. Please see the Company's response to Division 2-14 (a), filed on September 23, 2016. The Precedent Agreement between the Company and NGLNG is a confidential agreement.

b. Please see the Company's response to Division 2-16 (a), filed on September 23, 2016. The Precedent Agreement for Northeast Energy Center LLC liquefaction services is a confidential agreement.

Division 3-13

Request:

Re: For the NGLNG agreement, please:

a. Document all measures the Company has taken to ensure the availability of natural gas input for the liquefaction process at prices that will ensure the marketability of the LNG output from the facility for National Grid while still recovering the annualized fixed costs of that facility;

b. Provide the workpapers, data, analyses, and studies upon which the Company relies to assess the long-term economic viability of its commitment to that facility.

Response:

a. Please see the Company's responses to Division 2-16 (b) and Division 2-14 (c), filed on September 23, 2016.

b. Please see the Company's response to Division 2-16 (c), filed on September 23, 2016.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 3-14

Request:

Re: For the Northeast Energy Center, LLC agreement, please:

a. Document all measures the Company has taken to ensure the availability of natural gas input for the liquefaction process at prices that will ensure the marketability of the LNG output from the facility for National Grid while still recovering the annualized fixed costs of that facility;

b. Provide the workpapers, data, analyses, and studies upon which the Company relies to assess the long-term economic viability of its commit-ment to that facility.

Response:

a. Please see the Company's response to Division 2-16 (b), filed on September 23, 2016.

b. Please see the Company's response to Division 2-16 (c), filed on September 23, 2016.

Prepared by or under the supervision of: Elizabeth D. Arangio